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The use of dynamic models to evaluate potential large-scale CO_2 storage in the Gippsland Basin, Victoria, Australia

S. Hurter[a], P. Probst[a], D. Labregere[b], A. Garnett[c+] and H. Holl[d]

[a]*Schlumberger Carbon Services, Australia*
[b]*Schlumberger Carbon Services, Australia; now ConocoPhillips, Australia*
[c]*UQ Energy Initiative, University of Queensland (formerly ZeroGen Pty Ltd)*
[d]*Geodynamics, Australia*

Abstract

A specific workflow to identify sites of sustaining CO_2 injection rates of 1 Mt/a for decades was applied to the Gippsland Basin. Dynamic simulations attained injection rates of about 0.4-10 Mt/a (extreme cases). Permeability was the most important parameter determining injectivity. Total injected CO_2 ranged from 10-34 Mt up to 130-240 Mt. Without a portion of the offshore, injectivity and capacity are reduced considerably. At the end of the injection period, modeled overpressure at the seal is less than retention pressures. In some cases, CO_2 does not reach the seal, even after 1000 yrs. In other cases, seal is reached after the pressure begins to decline.

Keywords: Injectivity, dynamic, Gippsland, uncertainty, industrial, Golden Beach, Latrobe, Halibut.

1. Introduction

An approach to identify Large Scale Storage Sites (LASSIE) and prove up the capacity of sustaining between 1 and 4 million tonnes per annum (Mt/a) to a total volume of 40 to 200 million tonnes (Mt) is employed on the Gippsland Basin. The overall study area includes areas covered by both (a) the Greenhouse Gas (GHG) Geological Sequestration Act 2008 (Vic); and (b) the Petroleum (Submerged Lands) Act 1982 (Fig.1a). The storage play concept consists of the Lakes Entrance Formation (LE seal) and siliclastic reservoirs in the Cobia, Halibut and Golden Beach (GB) subgroups of the Latrobe Group (Fig. 1b) with the main focus on the deeper formation.

Three areas of interest (Area 1, Area 2 and Area 3) are selected for more detailed study. The focus of this paper is dynamic modeling of CO_2 injection in these areas. A regional geological model and integration of existing data (seismic and well data) is used to build static models for each area. The simulations serve several purposes, namely:

- Integrate existing data and better understand the impact of uncertainty on storage potential;

[+] Andrew Garnett. Tel.: +61 7 3346 7920;
E-mail address: a.garnett@uq.edu.au..

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- Assist in informing future work;
- Explore specific scenarios and understand the impact of parameter choices (and uncertainty) on plume development, pressure management for CO_2 storage and capacity;
- Provide preliminary models to evaluate potential containment over long periods of time; and
- Provide preliminary models to discuss potential impacts of GHG storage on hydrocarbon resources and other resources (e.g. geothermal) and brine displacement.

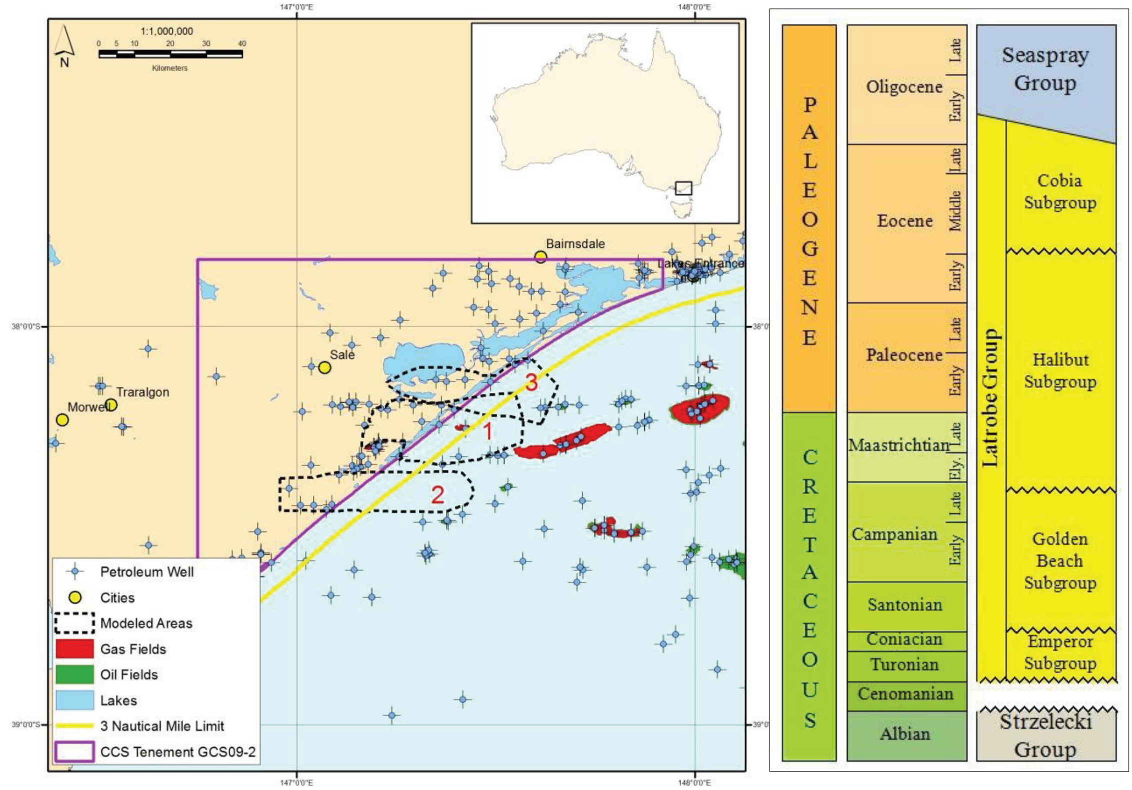

Fig.1. (a) LASSIE study area and model boundaries of 3 prospective sites. Tenement GCS09-2 is outlined in purple, oil and gas fields in green and red, respectively; yellow line indicates 3 nautical mile zone; (b) stratigraphic column of the Gippsland Basin.

2. Simulation tools and scenario definitions

The geological static model is created in Petrel. Dynamic simulations are performed with the software package ECLIPSE* reservoir simulation software with CO_2 specific enhancements [1]. Faults have not been incorporated except at the edges of the model to represent no-flow boundaries. At a later stage, it will include explicit faults.

The domain size is selected to minimize edge effects within the region of interest. Initially, the domain is in hydrostatic equilibrium with salinity of 11,000 ppm. A constant geothermal gradient of 3.1°C/100 m is imposed to calculate a temperature for each cell and temperature dependence of fluid properties. CO_2 is injected at reservoir temperature.

Injection rate can vary according to fluid and reservoir properties, but is limited by a fracturing gradient of 14.9 bar/100m (no safety margin). Due to the lack of relative permeability data for the Gippsland Basin, published data for the Viking sandstone from the Alberta Basin in Canada [3] are used. The implications of this proxy are not addressed, but measurements of this parameter are part of the appraisal plan. The maximum possible CO_2 saturation is 0.6 and residual saturation will be 0.3. In all cases, pure CO_2 is injected through a single vertical well for 25 yrs. Then, the well is shut-in and the post-injection evolution is followed for 200 years (in 2 cases up to 1000yrs). Injection well locations are placed to minimize exposure to legacy wells and avoid protected areas.

Area 1 has the most data and various scenarios are defined for it (Table 1). Two cases for permeability distribution address ambiguous data: a Reference Case and a High Permeability Case (ref. section 2.2 below). Two injection intervals are used: injection over the full thickness of the GB (long completion) or over a 100 m section in the lower part of the GB (short completion). The existence of a potential seal at the top of the GB of unknown extent is examined imposing a laterally extensive no flow boundary (GB seal). In the other models, the Lakes Entrance Formation is a no-flow boundary (LE seal). To test the robustness of the case for pressure impact on the LE, an extreme case assumes horizontal permeability (Kh) is the same as the vertical one (Kv): Kh/Kv=1. For all other cases, Kh/Kv=0.1. The influence of injection well location is examined with an offshore (OF) and onshore (ON) well.

Simulations for Areas 2 and 3 use a simpler parameter space, but explore the implications of the specific locations. The permeability is uniform and injection is over the total section.

Table 1. Summary of dynamic modeling scenarios (9 cases)

	Permeability Distribution Model		Seal	Kv/Kh	Injection Horizon	Injection Interval (m)	Well Location	Total Injected CO_2 (Mt)
1	Area 1	Reference (basic)	Lakes Entrance	0.1	Golden Beach	Long	Offshore OF	28
2	Area 1	Reference	Lakes Entrance	0.1	Golden Beach	Short (100m)	Offshore OF	13
3	Area 1	Reference	Lakes Entrance	1.0	Golden Beach	Long	Offshore OF	34
4	Area 1	Reference	Top Golden Beach	0.1	Golden Beach	Long	Offshore OF	21
5	Area 1	Reference	Lakes Entrance	0.1	Golden Beach	Long	Onshore ON	10
6	Area 1	High permeability	Lakes Entrance	0.1	Golden Beach	Long	Offshore OF	239
7	Area 1	High permeability	Top Golden Beach	0.1	Golden Beach	Long	Offshore OF	132
8	Area 2		Lakes Entrance	0.1	Halibut	Long	Onshore A2	40
9	Area 3		Lakes Entrance	0.1	Halibut	Long	Shoreline A3	48

2.1. Static model

The static model is based on surfaces obtained from 2D seismic surveys and well tops correlation. Three surfaces were obtained: Top Latrobe Group, Top Golden Beach Subgroup and Top Emperor Subgroup. The Top Latrobe and the Top Emperor form the top and bottom boundaries of the model, respectively, that contain the Golden Beach Subgroup overlain by the Halibut-Cobia Subgroups (Fig. 2).

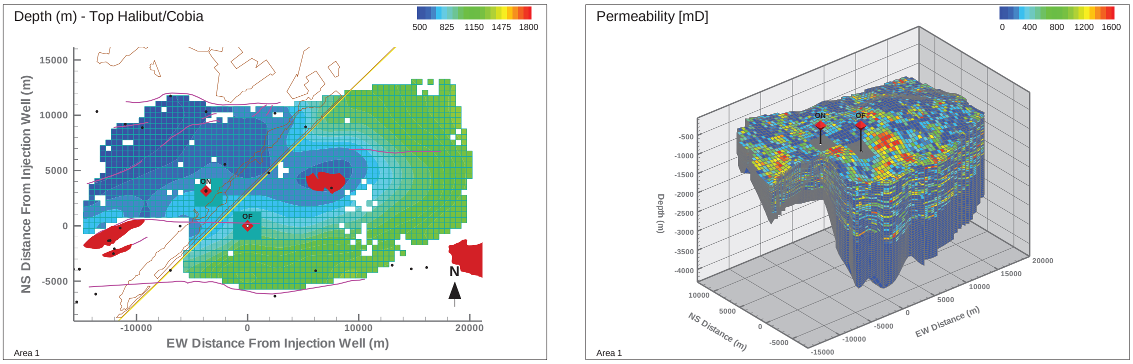

Fig. 2. (a) Depth of the Top Golden Beach in Area 1. Inactive cells are white, faults are in pink, gas fields in red and legacy wells are black. Distances given in meters counted from the model offshore well (OF). Onshore well is marked ON. Shoreline is yellow and brown contours protected surface areas. (b) Permeability for Reference Case. Lower section is more uniform at10-100 mD (green and yellow colors), while the upper part is more heterogeneous with high (1 D, in red) and very low values (< 0.1 mD, blue).

The faults to the North and South, as well as the limits of the pinch-out of the GB form natural lateral boundaries. Other boundaries are arbitrary and located far from the injection well, to avoid its influence in models. The virtual offshore injection well (OF) is situated where the GB is at a depth of about 2100m and the onshore (ON) well intercepts the Golden Beach Subgroup at *ca.*1400m depth. Laterally, the model grid is 500m x 500m. Vertically, the Halibut-Cobia and Golden Beach Subgroup sections are divided into 30 and 20 conformable layers, respectively. The vertical grid varies from 4-76m. Local grid refinement (LGR) was applied up to 1.5km distance from the well so the grid is reduced to 50m x 50m.

2.2. Material properties

Each grid cell needs to be populated by a single value for porosity, net-to-gross and permeability. Properties derive from ELANPlus* advanced multi-mineral log analysis of the Dutson Downs-1 and Golden Beach-1A wells. The upscaling process for the net-to-gross ratio (N/G) combines the volume of clay (VCL) and the effective porosity (PIGE) in the ELANPlus analysis. Net-to-gross (N/G) is equal to 1 (reservoir) when porosity is higher than 10% and Volume of Clay is less than 30%, otherwise net-to-gross is equal to 0 (seal). A *High Permeability* scenario (High-K) was generated by adding 60 mD to each value of the ELANPlus permeability log (*Reference Case)* in the Golden Beach Subgroup with N/G =1. The High-K Case was built to honor the relatively high core permeability measured in Golden Beach-1A. Sequential Gaussian Simulation is used to populate the model properties beyond the well locations (Fig 2b). A variogram analysis honors the initial data distribution. Properties are generated assuming they obey a normal distribution, reflecting the lack of information for a better distribution.

Only one generalization is presented and was computed. At the level of current uncertainty, many more realizations would not bring more insight to inform and help structure a future work plan.

3. Simulation results and interpretation

The outcomes of the simulation are injection rates, the distribution of CO_2 and pressure within the model domain as a function of time, the partition of dissolved, free-phase (mobile) and residually trapped (immobile) CO_2 through time. Results are generally displayed after 25 yrs of injection and 200 yrs later.

3.1. Injectivity

Injectivity for all scenarios of Area 1 are displayed in Fig. 3 and in Table 2. Both scenarios that plot above 1Mt/a are offshore injection scenarios over the complete GB. Reference Case with Kv/Kh = 0.1 (green) 1.1 Mt/a. Above it, the case with Kv/Kh=1, attains 1.4 M/yr. All other scenarios inject less than 1 Mt/a. The effect of an extensive seal at the top of the Golden Beach Group (orange) is less accommodation space for injected CO_2 than in the cases with the Lakes Entrance top seal. Maximum BHP is set as a constraint, hence injectivity reduces in response to pore pressure increases over a 25 year period (10 Mt). Injection over a shorter interval (S, 100 m) decreases injectivity to 0.5 Mt/a (blue), and 13 Mt are accumulated in 25 yrs. By comparison, an onshore setting allows less than half the injection rate (0.4 Mt/a) than the offshore injection rate. Total amounts injected over 25 yrs are 10 Mt and 28 Mt, respectively. The onshore scenario indicates that more wells would be required for industrial storage, however, it could represent an initial development which expands later to the offshore.

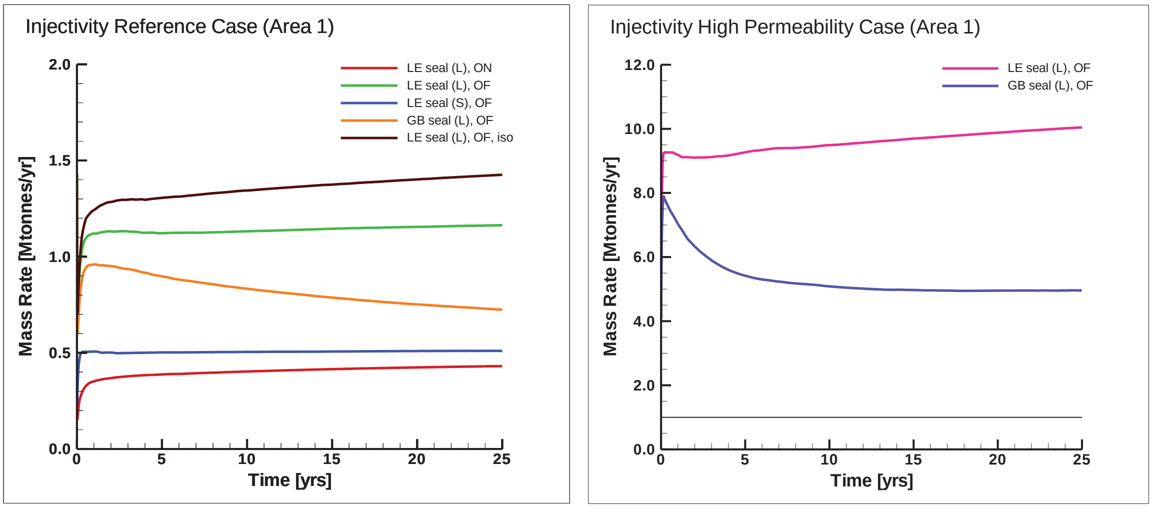

Fig. 3. Modeled injection rate as a function of time for (a) 5 scenarios of the Reference Case, and (b) injectivity for 2 scenarios of the High Permeability Case (see Table 1).

The High Permeability Cases consider the presence or not of a seal at the Top GB (Fig. 1b) and produce extremely high injection rates, up 5.0 Mt/a and up to 10 Mt/a, respectively, almost an order of magnitude greater than the Reference Cases (Fig 3). The total injected amounts over 25 yrs are enormous, 132 and 239 Mt. These rates are very unlikely, but serve to inform the potential containment performance of such extreme scenarios. Models for Areas 2 and 3 attain injectivity of 1.6 and 1.9 Mt/a, respectively.

Absolute permeability and its uncertainty has the greatest impact on injectivity compared to other factors. Measurements of this parameter are essential to be part of the Work Program to reduce uncertainty.

3.2. Plume and pressure evolution

First, injection pressure dominates the migration of injected CO_2 displacing it radially from the injection well. Reservoir heterogeneity and buoyancy then affect the shape and evolution of the CO_2 plume. After injection stops at 25 yrs, only gravity and the vertical heterogeneity influence the plume. Generally, thereafter, the plume does not increase much and remains fairly stable at the resolution of the model, probably due to low regional dip.

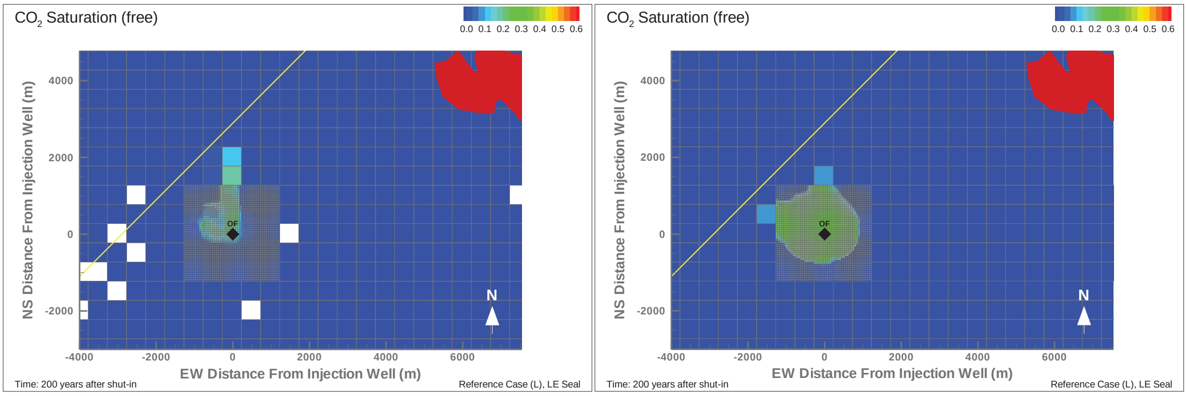

Fig. 4. Map view of CO_2 saturation at 200 yrs after injection has ceased. White line is the shoreline, white squares are inactive model cells and red area shows the Golden Beach gas field. (a) Distribution at the top of the GB, plume stretches up to 2.5km north. (b) Distribution at the Base Halibut-Cobia Subgroups with maximum lateral extension (2.5-3.0 km). Grey areas are areas of local grid refinement (LGR).

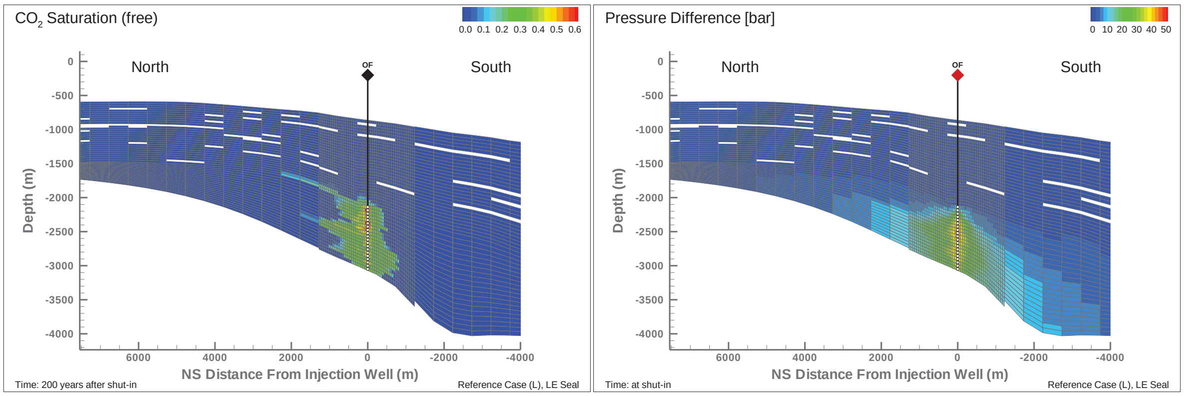

Fig. 5. North-south vertical cross-section through a plane containing the well shows: (a) CO_2 saturation at 200 years after end of injection. (b) overpressure at the end of 25 years of continuous injection. Grey areas are areas of LGR.

For one Reference Case example, the plume is shown in map view (Fig 4a,b) at 2 different depths, 200 yrs after injection has ceased. The different shapes are a function of the permeability heterogeneity. A vertical cross-section also shows the heterogeneous CO_2 saturation at 200 yrs (Figs. 5a). It is important to note that at the end of 200 yrs (as well as for 1000 yrs, not displayed here), no CO_2 reaches the LE potential seal. In the Reference Cases run up to 1000 yrs after injection stops, the small changes after 200 yrs can be attributed to slow dissolution of free-CO_2, and not to migration. CO_2 in the plume is in near residual saturation and the top of it is about 900 m below the potential seal. For the Reference Case, more than 80% of the injected CO_2 is removed (29Mt) from the free-phase which is mobile and buoyant.

In this model, there is no contact of CO_2 with the top seal and it does not experience overpressure. However in the scenario in which an extensive seal were to exist at the top of the GB, the large mass of injected CO_2 would have much less vertical accommodation space and would need to spread further laterally and updip extending over 14 km. A CO_2 cap accumulates in the onshore subsurface and pressures are higher: overpressure of the order of 50 bar affects a region of several kilometers around the injection well (Fig. 5).

4. Summary and conclusions

Despite the high uncertainty in the data, dynamic models of selected scenarios allow insights to be gained on the behavior of injected CO_2 into reservoirs of the Gippsland Basin. Table 2 summarizes the results. The models serve to illustrate the modeling strategy and purpose at this early stage of site selection: exploring the impact of uncertainty on potential storage performance.

Table 2. Summary of dynamic simulation results.

Area/Scenario	Injection Interval	Sustained Injectivity [Mt/a]	Total Injected in 25 years	Max lateral plume extent at 200 years [km]	Containment Max overpressure: 1) Near well 2) At seal
Area 1 Reference case, L LE seal	Golden Beach Subgroup	1.1	28	2.5	1) 52 bar 2) LE, 1.6 bar
Area 1 Reference case, S LE seal	Golden Beach Subgroup	0.5	13	2.5	1) 53 bar 2) LE, 1.2 bar
Area 1 Reference case, L LE onshore	Golden Beach Subgroup	0.4	10	3.5	1) 30 bar 2) LE, 1.1 bar
Area 1 Reference case, L sealed GB	Golden Beach Subgroup	1.0 - 0.7	21	2.5	1) 60 bar 2) GB, 60 bar
Area 1 High-K case, L Sealed GB	Golden Beach Subgroup	8-5	132	15.5	1) 71 bar 2)GB, 71 bar
Area 1 High-K case, L LE seal	Golden Beach Subgroup	9-10	239	9	1) 35 bar 2) LE, 8 bar
Area 2 Uniform layers	Part of Halibut subgroup (zone 2)	1.6	40	9	1) 6 bar 2) LE, 11 bar
Area 3 Uniform layers	Halibut subgroup	1.9	48	4	1) 10 bar 2) LE, 10bar

All scenarios assumed injection into a single well into a single geological formation (GB). There is upside to these assumptions in terms of additional wells, additional injection formations and optimised well designs. Lack of capacity is considered to be a minor risk. The results also suggest that including part of the 3 nautical mile zone in the tenement area is required for an industrial scale project. The low resolution models suggest that choosing the appropriate injection strategy and placing wells carefully allows pressure to be managed without exceeding capillary entry, fault reactivation or fracturing pressures and exposure of legacy wells to be minimized or even avoided. The critical data to decide on feasibility and, later, establish appropriate operations and storage constraints, are lacking at present. This can be mitigated with an appraisal campaign.

*Mark of Schlumberger

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